Bonneville Power Administration
Power Business Line

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Final Study

Chapter 4 – Secondary Revenue Forecast

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BONNEVILLE POWER ADMINISTRATION

CHAPTER 4: SECONDARY REVENUE FORECAST

4.1 Introduction

4.1.1 Definitions and Purposes. This chapter presents BPA's secondary revenue forecast for the SN CRAC power rate case. The secondary revenue forecast estimates the amount of revenue BPA expects to make in marketing its surplus energy. BPA used the AURORA model to estimate the prices BPA expects to receive in the surplus energy market. AURORA calculates the variable cost of the marginal resource in a competitively priced energy market. In competitive market pricing, the marginal cost of production is equivalent to the market-clearing price. Market-clearing prices are important factors in determining BPA's bulk power revenues. Therefore, the marginal clearing price estimates inform BPA's forecast of secondary revenues in the rate case. Chapter 6 of this study, Risk Analysis, explains the use of AURORA prices in determining the secondary revenue forecast.

4.1.2 AURORA Model Framework. AURORA assumes a competitive pricing structure as the fundamental mechanism underlying the determination of wholesale electric energy prices during the term of this analysis. Two fundamental inferences for energy pricing follow from the economic theory of market pricing. First, the price in any hour will approximate the variable cost of the marginal generating resource. Second, the long-term average price will gravitate toward the full cost of a new resource.

As noted above, the inference on hourly prices follows directly from economic market pricing theory. Economic theory concludes that a firm will continue to produce additional goods or services as long as the revenue from the sale of those units covers the marginal cost. A competitive market will produce up to the quantity where the amount consumers are willing to pay for marginal consumption is equal to the marginal cost of production. Therefore, the market-clearing price is equal to the cost to produce the marginal unit for consumption. For the electricity market, the hourly market-clearing price translates to the variable cost from the marginal electric generator.

In the long-term, when the amount of capital is not fixed, the average price will move toward the full cost of a new resource. When prices are high enough to justify additional investment, the average investment cost will be lower than the average price. Therefore, new resources will be built bringing down the price. When the long-term average price outlook is lower than the average cost of a new resource, new resources will not be built. In this case, demand growth will move prices up the supply curve until new resource investment is profitable.

Since long-term prices will gravitate toward the cost of new resources, the assumptions concerning the cost of a new resource will have an important impact on the long-term price forecast. It is assumed that the bulk of new electric power generation will be combined-cycle combustion turbines (CCCT). Another important assumption is the load forecast. This assumption will affect how quickly prices move up the supply curve and reach the point where investment in new resources is profitable.

Economic theory also concludes that until prices reach the level where new resource investment is profitable, excess capacity will decline. A decline in excess capacity will tend to exacerbate price increases in those periods where capacity is relatively less surplus: the peak pricing months and heavy load hour periods. The average levels of monthly prices and the heavy and light load hour prices for each month are given in section 4.4 of this chapter.

4.2 Methodology

4.2.1 Overview. The principal tool used in this analysis is an electric energy market model called AURORA. AURORA is owned and licensed by EPIS, Incorporated. Production costing is a subset of AURORA's functions. Production cost models are widely used in the electric power industry. Production cost models follow a general structure and AURORA is consistent with this structure.

To describe AURORA’s methodology it is helpful to distinguish between two main aspects of modeling the electric energy market: the short-term determination of the hourly market-clearing price and the long-term optimization of the resource portfolio.

4.2.2 Hourly Price Determination. The hourly market-clearing price is based upon a fixed set of resources dispatched in least cost order to meet demand. The hourly price is set equal to the variable cost of the marginal resource. AURORA sets the market-clearing price using assumptions on demand levels (load) and supply costs. The supply side is defined by the cost and operating characteristics of individual electric generating plants, including resource capacity, heat rate, and fuel price.

AURORA recognizes the effect that transmission capacity and prices have on the ability to move generation output between areas. AURORA recognizes 13 areas within the Western Electricity Coordinating Council (WECC, formally called the WSCC), largely defined by the transmission grid.

4.2.3 Long-Term Resource Optimization. The long-term resource optimization feature within AURORA allows generating resources to be added or retired based on economic profitability. Economic profitability is measured as the net present value of revenue minus the net present value of costs. A potential new resource that is economically profitable will be added to the resource database. An existing resource that is not economically profitable will be retired from the resource database.

In reality, the market-clearing price (hence the profitability of a resource) and the resource portfolio are interdependent. The market-clearing price will affect the revenues any particular resource will receive, and consequently which resources are added and retired. In parallel, changes in the resource portfolio will change the supply cost structure and will therefore affect the market-clearing price. AURORA uses an iterative process to address this interdependency.

AURORA's iterative process uses a preliminary price forecast to evaluate existing resources and potential new resources in terms of economic profitability. If an existing resource is not profitable, it becomes a candidate for retirement. Alternatively, if a potential new resource is economically profitable, it is a candidate to be added to the resource portfolio. In the first step of the iterative process, a small set of new resources is drawn from those with the greatest profitability and added to the resource base. Similarly, a small set of the most unprofitable existing resources is retired. This modified resource portfolio is used in the next step in the iterative process to derive a revised market-clearing price forecast. The modified price will then drive a new iteration of resource changes. AURORA will continue the iterative solution of the resources portfolio and the market-clearing price until the difference in price between the last two iterations reaches a minimum and the iterative process converges to a stable solution.

4.2.4 Application of AURORA for the Secondary Revenue Forecast. For the secondary revenue forecast, AURORA was run in a probabilistic mode. When running the probabilistic forecast, BPA altered hydro conditions, load conditions, and natural gas price conditions. The methodology and resulting variations around the inputs are found in chapter 6 of this study, Risk

Analysis. The Risk Analysis study provided the variations in the inputs that were used to supply AURORA. AURORA was run for 3,000 games with monthly average HLH and LLH prices forecasted for the remainder of the rate period. The resulting prices were then used in RiskMod to derive the probabilistic secondary revenue forecast.

As stated in the testimony of Oliver, *et al.*, SN-03-E-BPA-08, BPA decremented the loads in Oregon, Washington, and Northern Idaho by 2,500 aMW to reflect the fact that BPA does not market power in a market that has an exact hourly marginal clearing price. Instead, BPA markets power in a bilateral market in which every party does not receive the highest hourly marginal clearing price. To decrement the loads in Oregon, Washington, and Northern Idaho in RiskMod by 2,500 aMW, BPA lowered the expected value load forecast for those areas by 2,500 aMW.

4.3 Assumptions

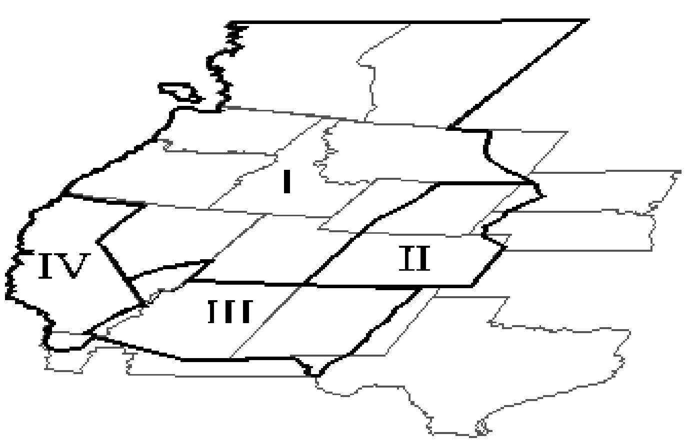
4.3.1 Overview. There are three primary assumptions that are relevant to the secondary revenue forecast: the load forecast, the natural gas price forecast, and the assumptions about hydro conditions. The load forecast determines where on the supply curve the marginal clearing price is determined. Natural gas prices will generally determine the variable cost of the resource on the margin that sets the marginal clearing price. Hydroelectric generation conditions determine the amount of hydroelectric generation that can be used to meet loads and thus add to the location on the supply curve in which the marginal clearing price is determined. Consequently, the assumptions on the load forecast, natural gas prices, and hydro conditions are described in detail in this section.

A number of other relevant assumptions are discussed in the following sections. Remaining data and assumptions that are required to run AURORA are listed in the documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 4.

4.3.2 Load Forecast. The load forecast for AURORA consists of four parts: the base-year load forecast; the annual average growth rate; monthly load shape factors; and hourly load shape factors. The base year load forecast determines the starting level for the loads. The annual average growth rate increases the loads over time. The monthly load shape factors shape the annual loads into monthly loads. The hourly load shape factors then shape the monthly loads into hourly loads.

4.3.2.1 Base-Year Load Forecast. For the base-year load forecast input to AURORA, BPA relied on the WECC Summary of Estimated Loads and Resources, Data as of January 1, 2002, issued May 2002. The WECC forecasts loads for four regions: (I) the Northwest Power Pool Area (split into U.S. and Canada systems); (II) the Rocky Mountain Power Area; (III) the Arizona–New Mexico–Southern Nevada Power Area; and (IV) the California–Mexico Power Area. Figure 4-1 represents these areas:

Figure 4-1: 2002 WECC Regions



Where: I = Northwest Power Pool Area

II = Rocky Mountain Power Area

III = Arizona–New Mexico–Southern Nevada Power Area

IV = California–Mexican Power Area

The four WECC regions were converted into 13 AURORA areas for BPA's forecasts. Table 4-1 represents the 13 AURORA areas:

Table 4-1: AURORA Areas

AREA NUMBER	AREA NAME	SHORT AREA NAME
1	Oregon/Washington/IdahoNorth	OWI
2	Northern California	NoCA
3	Southern California	SoCA
4	British Columbia	BC
5	Idaho South	IDSo
6	Montana	MT
7	Wyoming	WY
8	Colorado	CO
9	New Mexico	NM
10	Arizona/NevadaSouth	AZNV
11	Utah	UT
12	Nevada North	NVNo
13	Alberta	AB

The methodology used to convert the WECC regional loads can be seen in the following example. With the Northwest Power Pool Area (U.S. Area), the loads in the original AURORA database for OWI, IDSo, MT, UT, and NVNo, were summed to produce an aggregate total load. The loads for OWI, IDSo, MT, UT, and NVNo, were each divided by the aggregate total load to develop individual percentages. The individual percentages were then applied to the aggregate WECC regional load forecast for the Northwest Power Pool Area 2001 load forecast for

AURORA areas OWI, IDSo, MT, UT, and NVNo. This procedure was then repeated for each of the WECC regions to derive each AURORA area base-load forecast. For this chapter, the PNW is the synonymous with the OWI, IDSo and MT areas.

4.3.2.2 Annual Average Growth Rate. BPA used an average annual growth rate from the WECC 10-Year Coordinated Plan Summary 2001-2010. BPA used these WECC regional growth rates to reflect its prediction that loads will grow at different rates in the different WECC regions. Table 4-2 shows the WECC annual growth rates used in the Secondary Revenue Forecast:

Table 4-2: Load Forecast Annual Average Growth Rate in Percents

Area	NWPA	RMPA	AZ/NM/SO NV	CA-MX
2002	1.9	3.1	3.6	2.6
2003	1.7	3.2	3.0	2.7
2004	1.7	2.5	2.1	2.7
2005	2.0	2.1	3.0	2.7
2006	1.8	2.1	2.8	2.7

BPA applied the annual average growth rate to the base load forecast to determine the load forecast over time.

4.3.2.3 Monthly and Hourly Load Shaping Factors. BPA used the default AURORA load shaping factors for converting the annual load forecast into a monthly load forecast. AURORA multiplies the monthly shaping factor by the annual load forecast to derive the monthly load forecast. BPA also used the default AURORA hourly load shaping factors provided for converting the monthly load forecast into an hourly load forecast.

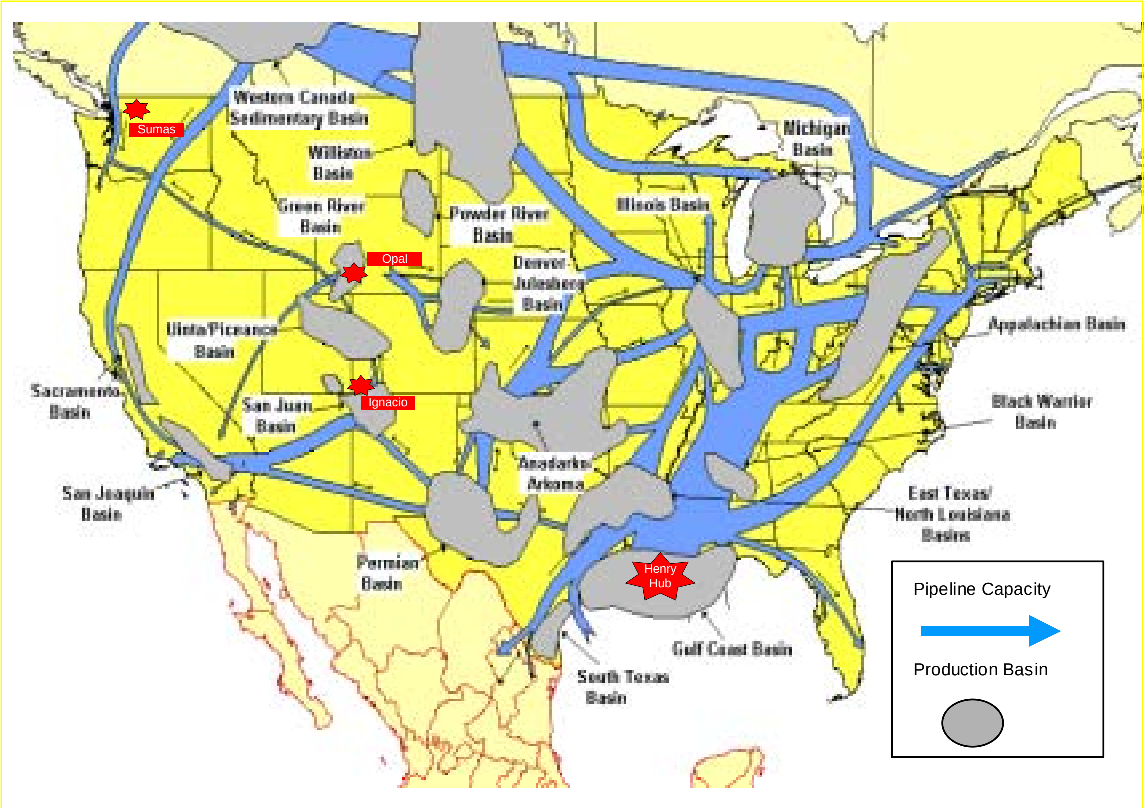
4.3.3 Natural Gas Prices

4.3.3.1 Methodology. This section describes the methodology used to forecast natural gas prices. The methodological description first covers the geographic aspect of the natural gas price forecast and then the temporal aspect of the forecast.

The purpose of the geographic component of the natural gas analysis is to derive a forecast for gas delivered to electric generators in each of the AURORA areas. Natural gas prices in these areas are largely determined within the interconnected North American market. However, transportation costs and local supply and demand factors also affect local prices. The methodology begins with a proxy for prices in the North American market and then estimates the difference between this price and local prices.

The methodology begins with a forecast of natural gas prices at Henry Hub in Louisiana. This Hub is frequently referenced as a touchstone for North American gas prices and is the location of the most liquid natural gas futures market. The next step in the geographic disaggregation of gas prices estimates a price difference, or basis, between Henry Hub and three primary natural gas supply basins in the west. These basins are the source for most of the natural gas delivered in the western U.S. Conditions in these basins are represented by pricing hubs associated with the supply basins. The Western Canada Sedimentary Basin is represented by the Sumas, Washington Hub. The collection of Rocky Mountain supply basins are represented by the Opal, Wyoming hub. The San Juan Basin is represented by the Igancio, Colorado hub. These three western hubs along with the supply basins and natural gas transportation flows are summarized in the Figure 4.2.

Figure 4-2: North American Natural Gas Geographic Summary



The final step in the geographic disaggregation of gas prices associates each western hub with an AURORA area and estimates the price differential between the hub and the AURORA area. The hub associated with each area is the hub that tends to be the source of marginal gas supply source in that area and therefore the hub that has the highest price correlation to prices in the local area. The Sumas hub is associated with the Pacific Northwest and Northern California areas. The Opal hub is associated with Montana, Idaho, Wyoming, and Utah. The Ignacio hub is associated with Nevada, Southern California, Arizona and New Mexico.

In summary, the forecast begins with a price forecast for Henry Hub. The difference between Henry Hub and each western hub is then forecast. The final step forecasts a price difference between the western hub and its associated AURORA area. The values of the price differentials are described in the Basis Results section.

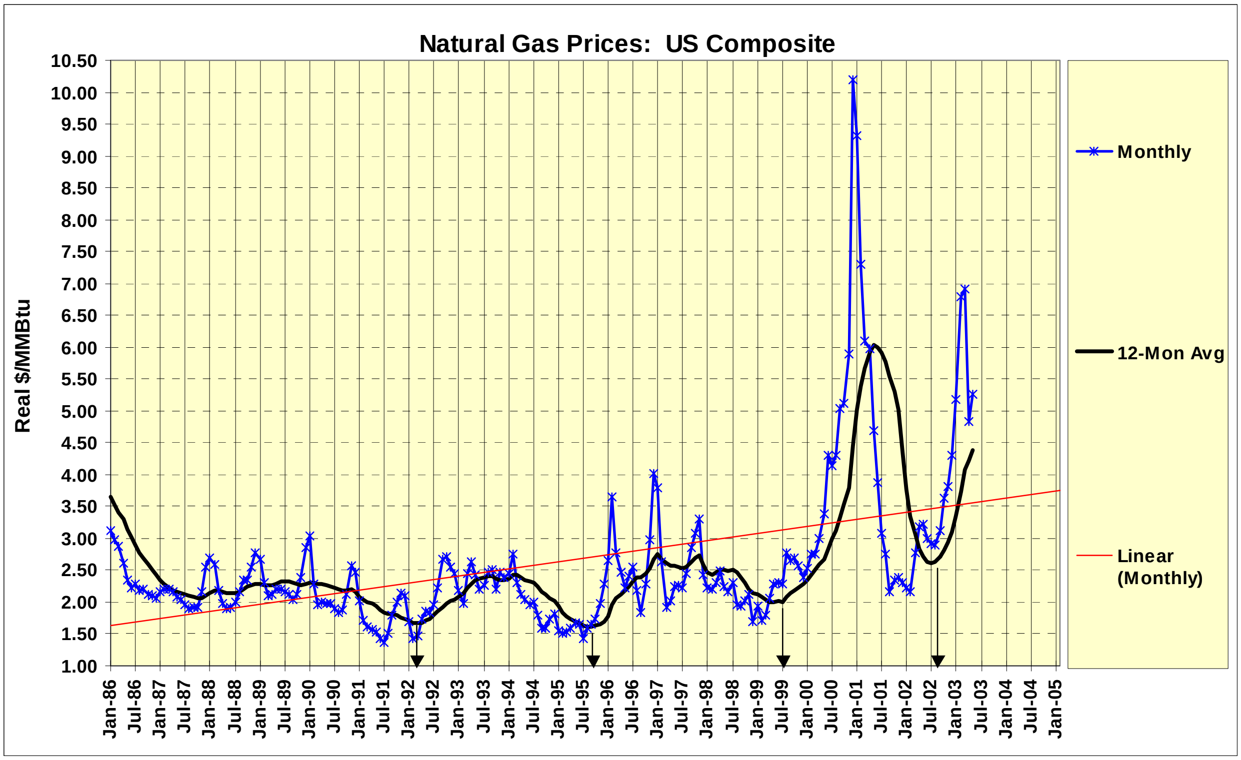
The temporal aspect of the natural gas forecast methodology uses New York Mercantile Exchange (NYMEX) futures prices to forecast short-term prices (through 2003) for Henry Hub. This short-term Henry Hub price forecast uses an average of futures market prices from ten days. A ten-day average was used to avoid any excessive or unexplained volatility that can result from daily fluctuations in futures market trading. After 2003, the price forecast was based on supply and demand fundamentals. These fundamentals and the resulting prices are described in the following sections.

4.3.3.2 Fundamentals Outlook. This section describes the outlook for the supply and demand factors that determine the price forecast. The section begins with a review of historic trends in the natural gas market. Next, the section gives a summary of the supply and demand factors in the forecast and a price forecast summary. This is followed by a more detailed description of supply and demand factors. The section closes with a summary of the fundamentals and price forecast. All natural gas prices are given in terms of real (inflation adjusted) dollars for the year 2000 unless otherwise stated.

4.3.3.2.1 Historic Review of the Gas Market. Wholesale natural gas prices were deregulated over a period of years from the 1970s to the early 1990s. From the mid-1990s the wholesale natural gas market has followed supply and demand factors. The following text describes the price trend and the supply and demand interactions. This review will lay the groundwork for the supply and demand outlooks that drive the price forecast.

From the mid-1990s prices have shown a general upward trend, but with a cyclical component. The following graph shows monthly prices, a 12-month rolling average price series and a linear trend of monthly prices from January 1998.

Figure 4-3: North American Natural Gas Historic Prices

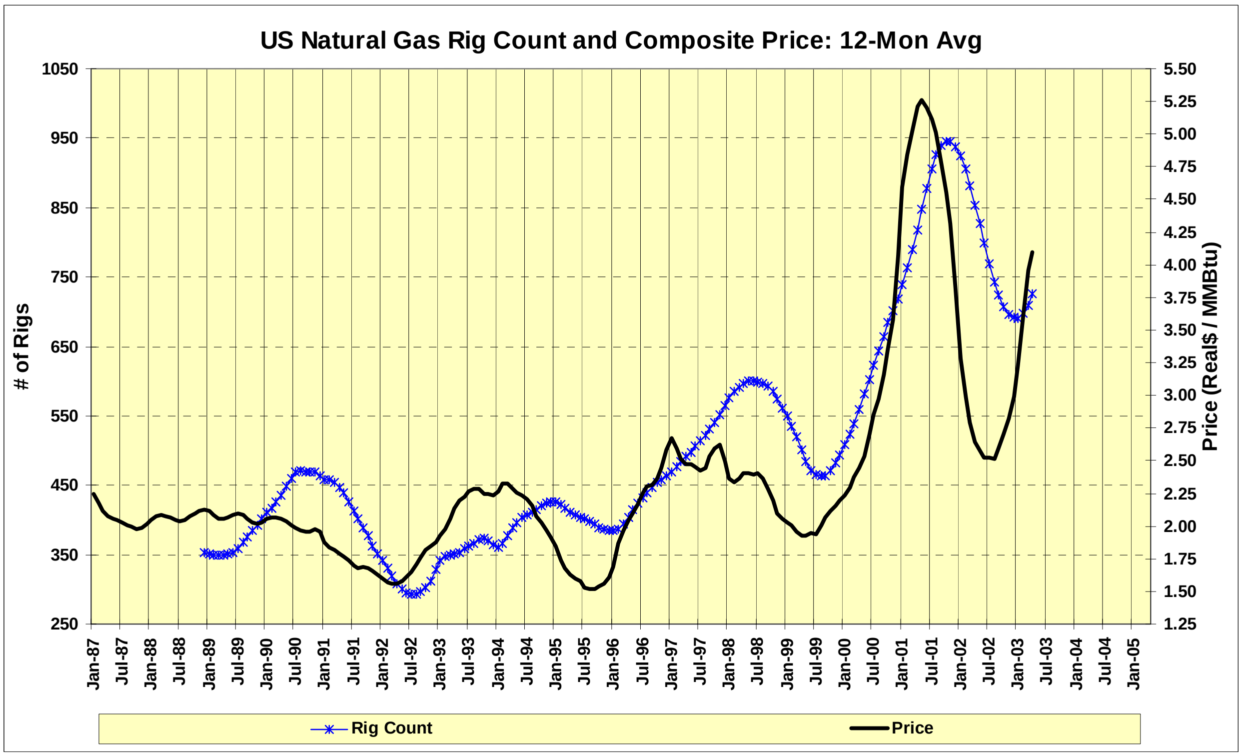


The linear trend shows the overall upward direction of natural gas prices. This is representative of the structural component of the natural gas that is based on long-term supply and demand factors. The underlying factors behind this trend are a robust demand for natural gas and the maturation of existing supply basins with the resulting drop in productivity. Technological improvements in gas supply have mitigated the upward trend in natural gas costs.

The cyclical aspect of natural gas prices is shown by the rolling 12-month average price. The arrows added to the graph show the approximate low point of the cycles, which tend to last from three to four years. For most of this historical period, the cyclical component of gas prices has been driven by a supply response. Demand has not been as responsive to price as supply. However, in the current cyclical upturn which began in the summer of 2002, demand has responded quite significantly.

The next two graphs illustrate the nature of supply and demand interactions with natural gas prices. The following graph overlays the supply picture, as measured by the rig count (the number of natural gas directed drilling rigs), with natural gas prices. Both series are a 12-month rolling average.

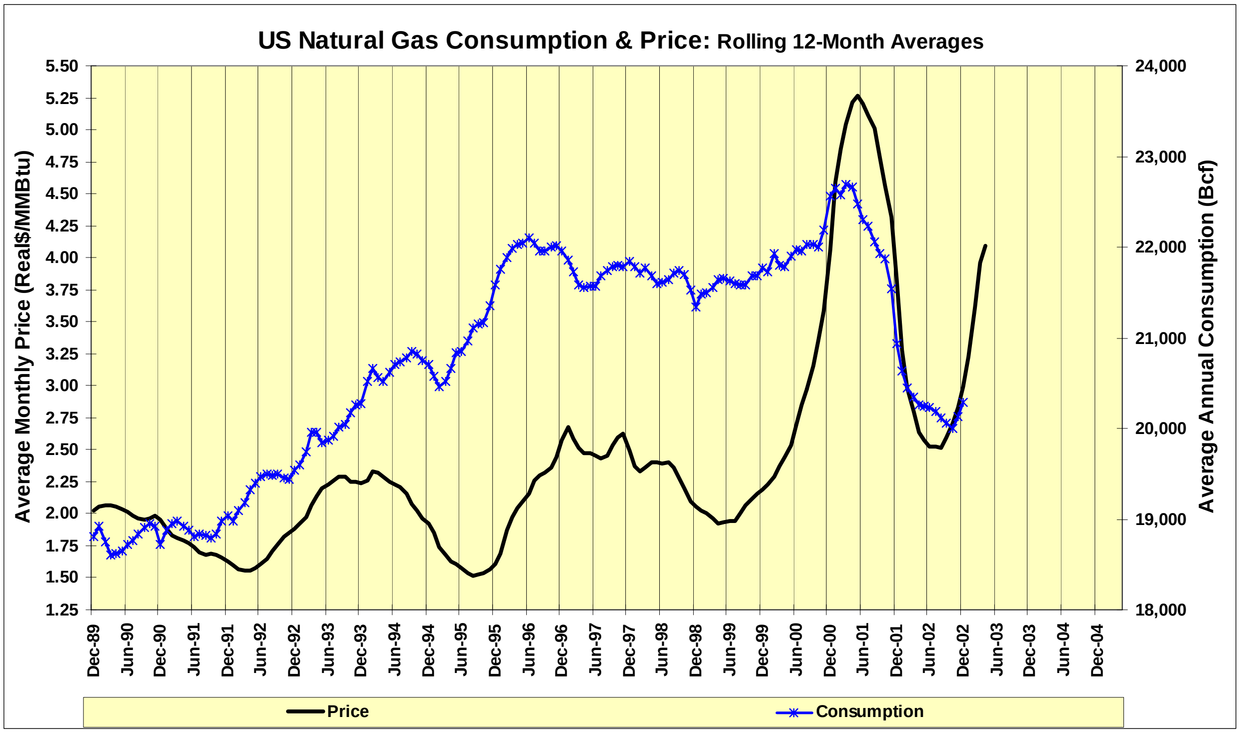
Figure 4-4: Natural Gas Supply and Prices



The rig count has historically followed natural gas prices with an approximate six-month lag. The supply response pattern is typical of a capital intensive industry with relatively long lead times for developing new supply. Natural gas rigs are currently following the price increase and began increasing (on a 12-month average basis) in early 2003.

The overlay of demand and prices in the following graph shows a quite different pattern from the supply side.

Figure 4-5: Natural Gas Demand and Prices



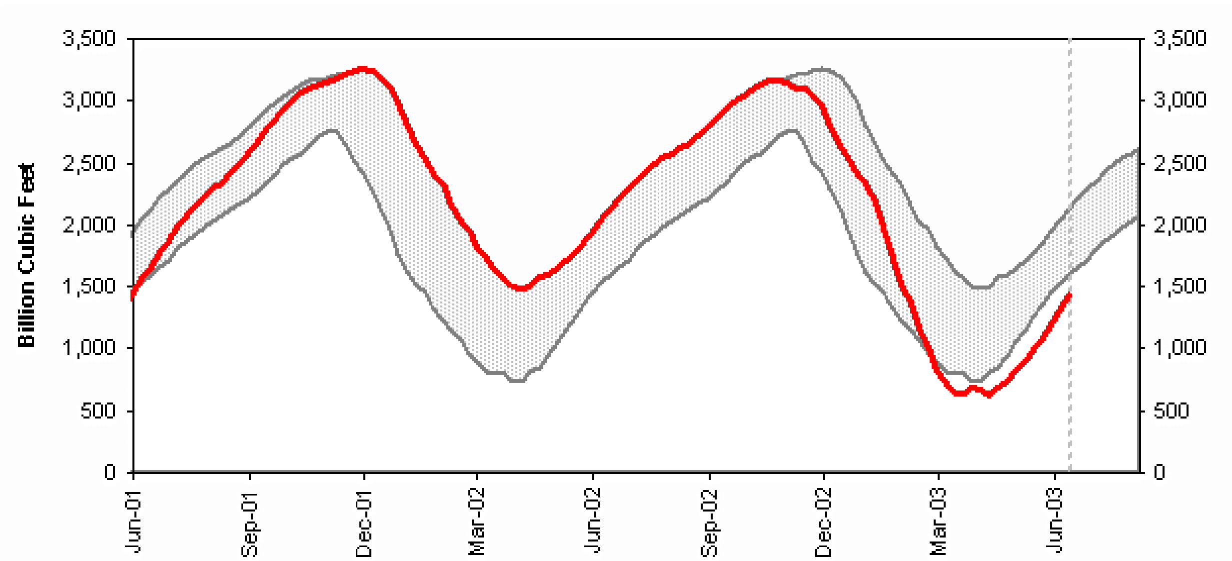
Natural gas demand grew fairly consistently until the mid 1990s. This was followed by a relatively flat pattern through the 1990s. Recently, natural gas consumption has fallen sharply. This decline is coincident and partially explained by a slowdown in the U.S. economy.

The decline in consumption has been most pronounced in the industrial and electric generation sectors, which are most exposed to wholesale price fluctuations. Industrial sector consumption is relatively price elastic. Some of the reduction in the electrical generation sector may result from newer, more efficient gas-fired generation replacing older and less efficient units.

4.3.3.2.2 Supply Outlook. The supply outlook is described over three time periods. In the short-term (through 2003), storage levels are a primary supply determinant. In the mid-term, (2004 and 2005) cyclical production becomes more important. In 2006, the supply outlook is driven by a long-term perspective.

For the remainder of 2003, very low storage levels will exert upward pressure on natural gas prices. Low storage creates high demand for refill and also contributes to a market psychology to support high prices. This low storage is a primary driver behind the current cyclical price upturn. Current and historical levels of natural gas in storage are shown in the following graph. The shaded band shows the historical five-year range of storage for each month. The solid line shows the recent storage levels.

Figure 4-6: Working Gas in Underground Storage Compared with Five-Year Range

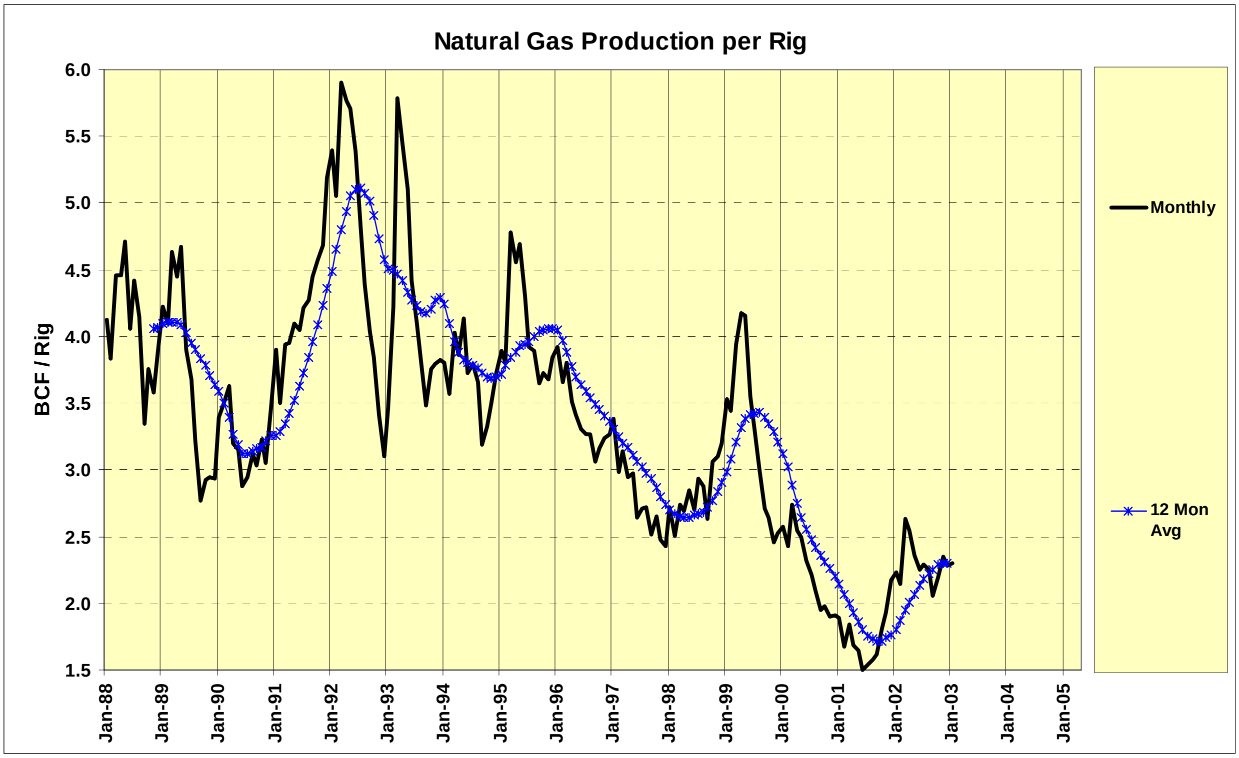


In the mid-term, after 2003, the level of natural gas production becomes a focus of the supply side. This mid-term supply outlook is consistent with the cyclical and structural factors described earlier. A cyclical upturn in gas drilling rigs began in early 2003 and is expected to continue. This increase in rigs will exert downward pressure on prices in 2004 and 2005.

However, this downward price pressure will be mitigated by the long-term structural trend in supply.

This long-term trend is based on the declining productivity of existing natural gas supply basins since the existing North American supply basins are now mature. This trend is shown in the following graph that measures the amount of production per natural gas rig.

Figure 4-7: Productivity Declines From Existing Supply Sources

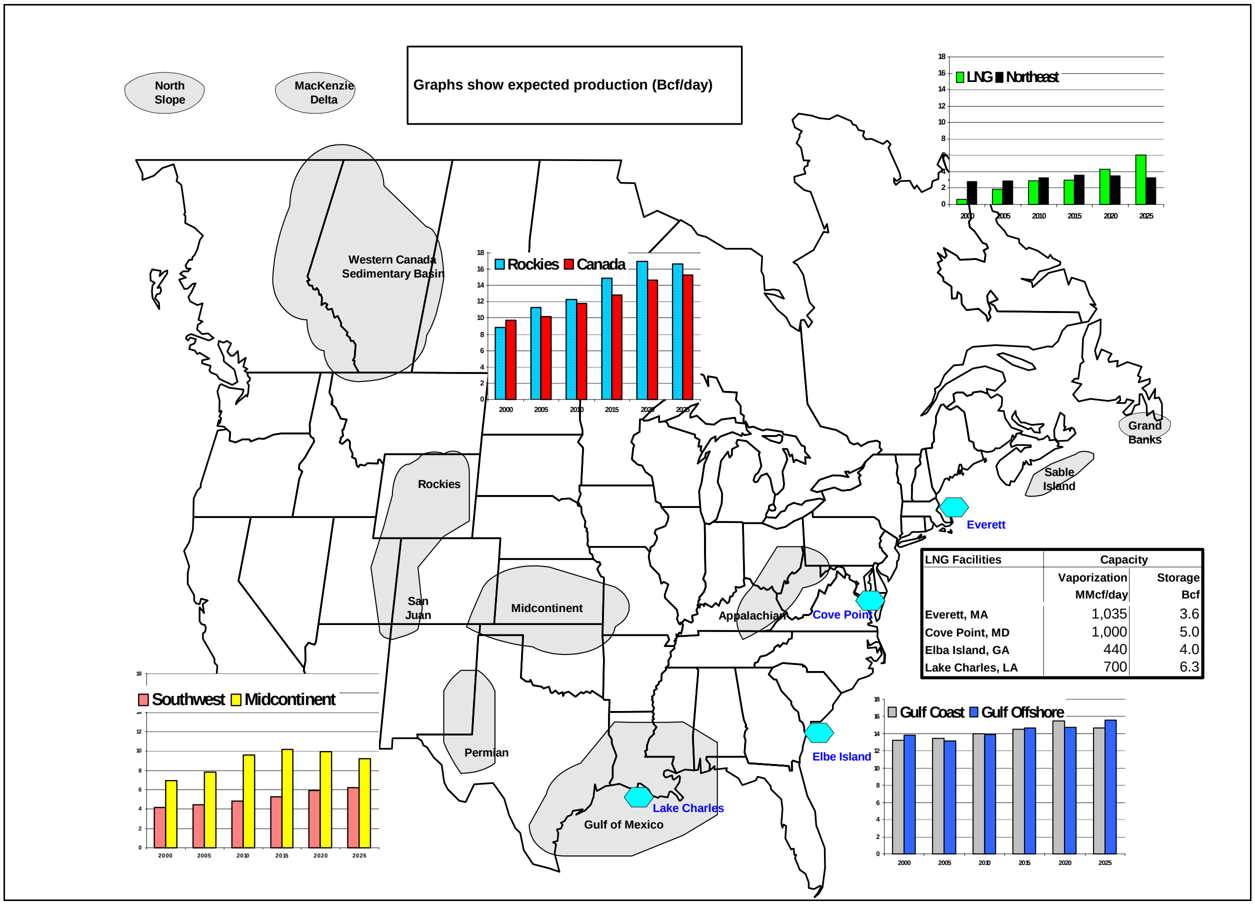


In the existing supply basins, the easiest to find and lowest cost gas has been tapped. Producers are increasingly moving to gas wells that have higher production costs. From 1992 to 2000 the average cost per foot of a gas well has increased sixty-three percent, from $85 per foot to $138 per foot.

An offset to increases in supply cost may come from new sources of supply. However, in the time horizon of this forecast, not enough new supply is expected to significantly affect the upward structural trend in natural gas prices. Supply increases are expected from the Rocky

Mountain basins and liquefied natural gas (LNG). However, these sources will not contribute enough new and inexpensive supply to change the upward structural trend. The long-term outlook for new supply by source is shown in the following figure.

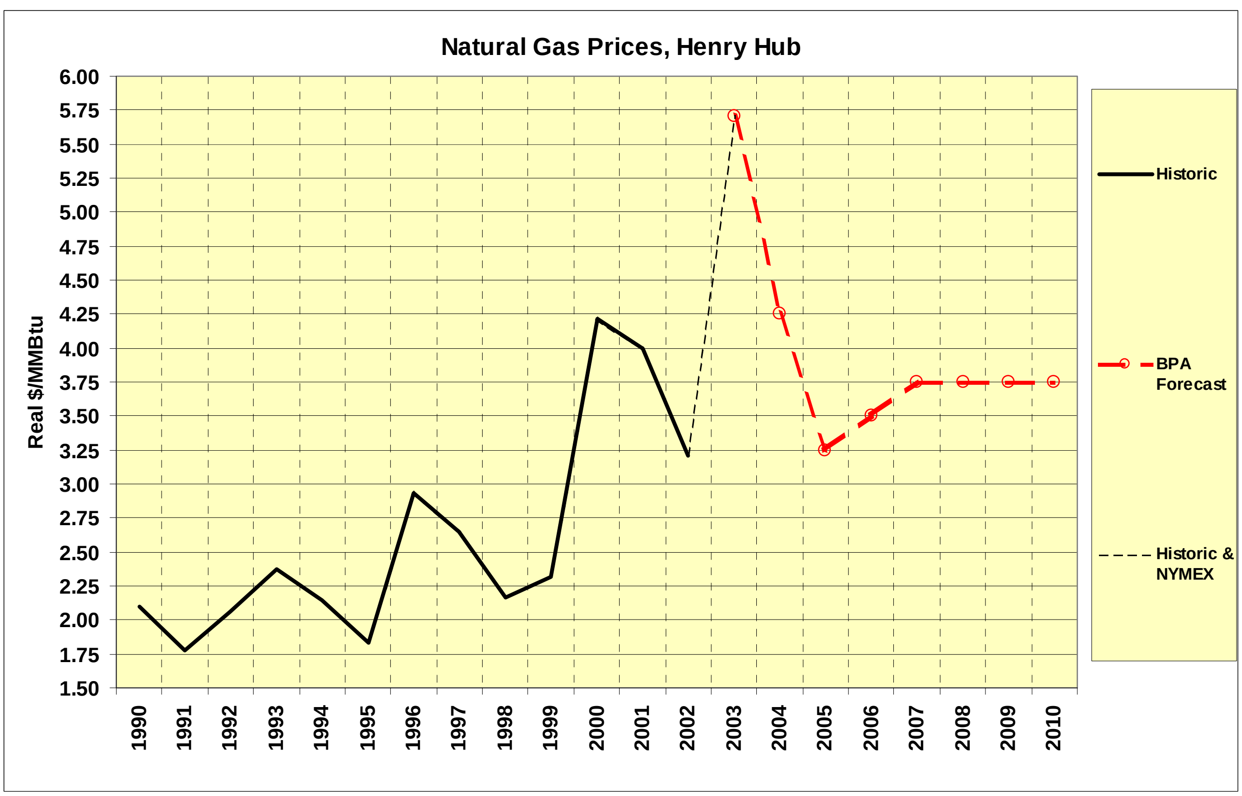
Figure 4-8: Long-Term Supply Outlook



4.3.3.2.3 Demand Outlook. The demand outlook assumes gas consumption will stabilize after 2003 and continue a growth pattern from 2004 to 2006. The factors contributing to the recent fall in demand are assumed to moderate. For overall demand, the weak U.S. economy is expected to have a moderate recovery. In addition, the demand response to price increases will be mitigated by the cyclical upturn in supply and the resulting downward pressure on prices. This will stabilize industrial and electric generation demand for natural gas. In the electric generation sector, the large majority of new generation will continue to be gas-fired. After initial efficiency gains, the reliance on natural gas for power generation is expected to increase the demand for natural gas.

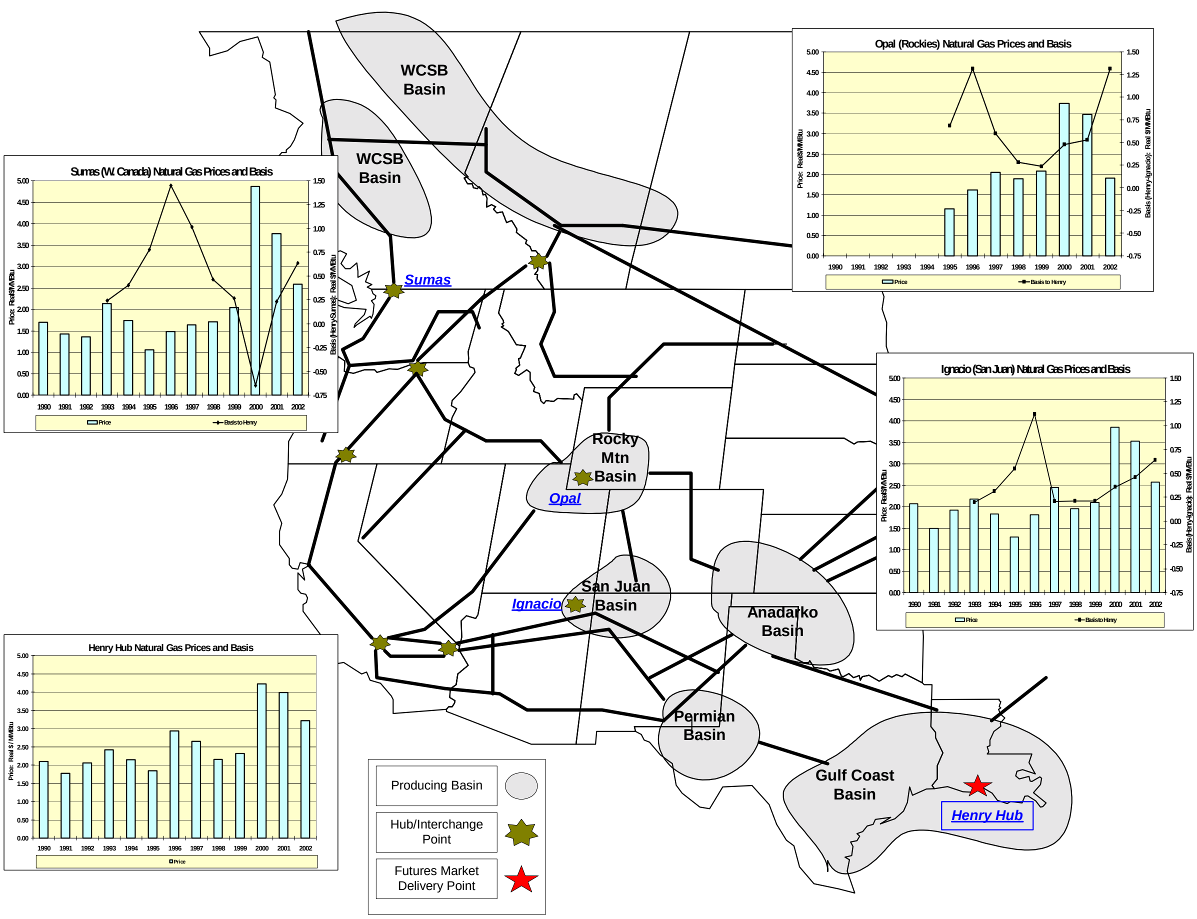
The North American market fundamentals and Henry Hub prices are summarized as follows. In the short-term (2003), very low storage will be the primary driver in maintaining the cyclical upturn in prices. In 2004 and 2005, the cyclical supply response will create a downturn in prices. Decreasing prices and a recovering economy will contribute to a stabilization of demand and a return to demand growth. However, the price downturn will be moderated by the long-term structural trend of declines in supply productivity and increased cost from existing supply sources. In 2006, prices are expected to rebound from the cyclical downturn and begin approaching an equilibrium level. The pattern of the Henry Hub gas price forecast is shown in the following graph and table.

Figure 4-9: Henry Hub Price Outlook



4.3.3.3 Basis Results. This section describes the forecast of price differentials between Henry Hub and the AURORA areas. The price differentials are a result of the transportation costs of natural gas and supply and demand factors. Pipeline bottlenecks can create a supply surplus in a local area because insufficient transportation capacity does not allow local gas to flow to higher priced markets and compete in the larger, North American market. When a bottleneck exists for an extended period of time, it becomes profitable to build new infrastructure to allow producers to capture the higher market prices. Absent pipeline bottlenecks, the price of natural gas tends to reflect general market conditions and the basis is a result of transportation cost differentials. Historical average price differentials can be used to gauge the price differentials that may result without extraordinary pipeline bottlenecks. The figure below maps the western supply system and shows historical price differentials to Henry Hub.

Figure 4-10: Western Natural Gas System



The Rocky Mountain supply has been constrained by pipeline bottlenecks. This has reduced prices in this area and resulted in a large basis to Henry Hub. In 2003, the Kern River pipeline expansion relieved this bottleneck and prices now more closely track the continental market. This decline in the basis from Henry Hub is reflected in the forecast of price differentials for the Rocky Mountain Supply from 2003 to 2004. Several smaller pipeline projects affect the basis of the other western hubs to Henry Hub. Historical and forecast prices for Henry Hub, the differentials to the western hubs, and the prices for the western hubs are shown in the following table.

Table 4-3: Historic and Forecast Natural Gas Prices for Hubs

Historic							*Forecast*							
Price				Basis			Price				Basis			
Henry	Sumas	Rockies	San Juan	Sumas	Rockies	San Juan	Henry	Sumas	Rockies	San Juan	Sumas	Rockies	San Juan
1.84	1.06	1.15	1.29	0.78	0.69	0.55							
2.93	1.48	1.62	1.81	1.45	1.32	1.12							
2.65	1.64	2.05	2.45	1.01	0.60	0.20							
2.17	1.71	1.89	1.96	0.46	0.28	0.21							
2.31	2.05	2.08	2.11	0.26	0.24	0.21							
4.21	4.86	3.73	3.86	-0.65	0.48	0.36							
3.99	3.76	3.46	3.53	0.23	0.53	0.46							
3.21	2.58	1.90	2.57	0.63	1.31	0.64							
							5.70	4.87	4.37	4.73	0.83	1.34	0.97
							4.25	3.65	3.55	3.65	0.60	0.70	0.60
							3.25	2.65	2.55	2.65	0.60	0.70	0.60
							3.50	2.90	2.80	2.90	0.60	0.70	0.60

The final step in the natural gas price forecast is to link the western hubs to the AURORA areas. The price differentials between the hubs and AURORA areas were adopted from the Northwest Power Planning Council's (NPPC) Draft Fifth Power Plan. The NPPC followed a similar methodology as described here. These pricing differentials are shown in the following table. The table lists the three western hubs and the associated AURORA area below. The value for each AURORA area is the price differential between the western hub and the AURORA area.

Table 4-4: Price Differentials Between Hubs and AURORA Areas

Aurora Area - Western Hub Price					
Sumas		Rockies		San Juan	
PNW	0.22	UT	0.34	Co	0.35
N. Cal	0.30	WY	0.39	S. Cal	0.45
		MT	0.32	AZ	0.40
		ID	0.34	NM	0.32
		N. NV	0.67	NV	0.45

The final AURORA area gas price forecast is derived by taking the western hub price and subtracting the differentials given in the table above. The results are shown in the following table.

Table 4-5: AURORA Area Price Forecast

Aurora Gas Price Forecast Input				
	2003	2004	2005	2006
Northwest	5.10	3.88	2.88	3.13
N. California	5.18	3.96	2.96	3.21
S. California	5.20	4.12	3.12	3.37
Canada	5.07	3.85	2.85	3.10
Idaho	4.72	3.90	2.90	3.15
Montana	4.70	3.88	2.88	3.13
Wyoming	4.77	3.95	2.95	3.20
Colorado	5.09	4.01	3.01	3.26
New Mexico	5.06	3.98	2.98	3.23
Arizona	5.14	4.06	3.06	3.31
Utah	4.72	3.90	2.90	3.15
Nevada	5.19	4.11	3.11	3.36

4.3.4 Hydroelectric Generation. For the secondary revenue price forecast, AURORA was supplied hydroelectric generation levels for the PNW area from Loads and Resources, chapter 2 of this study. For the California area, hydroelectric generation conditions were supplied from RiskMod. For the PNW, 50 water years were used for the variation in hydroelectric conditions. For the California area, 18 years of historical hydroelectric generation levels were used for determining hydroelectric generation variability. For the remaining areas, AURORA database default values were used. For monthly and hourly shaping factors, BPA used the AURORA default database. BPA made a very minor adjustment to the monthly shaping factor for the PNW for September changing the setting from .6 to .5.

4.3.5 Generating Resource Update. BPA updated generating resources to be consistent with the most current data available. BPA added specific resources expected to be operating through the 2003 time frame. After 2003, no specific resources were added. BPA let AURORA determine which generic resources would be added or deleted for 2003 and through the remainder of the study period. No new resources were added in the OWI area during the study period. A complete listing of all the resources can be found in the documentation for SN-03 Study, SN-03-FS-BPA-02.

4.3.6 Transmission Link Capacities. BPA updated the transmission link capacities to be consistent with the WECC path-rating catalog with the exception of two transmission paths. Those path ratings are the path rating between the OWI are and the NoCA (COB) area and the OWI area and the SoCA (NOB) area. These updates were both for ratings from North to South as well as South to North. BPA adjusted these ratings based on the fact that while the path rating is the maximum stated limit, history has shown that the maximum line rating is rarely available due to scheduled outages, forced outages, and loop-flow conditions. The line ratings were decreased to the annual average historical rating for the time frame 1999 to 2002. The line rating amounts can be found in the documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 4. For the final study, BPA also ran the model to reflect that there is a planned outage scheduled for the NOB path. NOB is scheduled to be de-rated to roughly 37 percent of maximum capacity for April 2004 – September 2004. The line will then be reduced to zero for October 2004 through December 2004. A complete listing of all the transmission link capacities can be found in the documentation for SN-03 Study, SN-03-FS-BPA-02.

4.3.7 Other Assumptions. For the secondary revenue forecast, BPA used AURORA version 5.6.33. AURORA was run sampling every other hour for Monday, Wednesday, Friday, and Sunday for the first and third week of every month. For the assumptions not mentioned above, BPA used the AURORA default database supplied with version 5.6.33. These assumptions are contained in the documentation for SN-03 Study, SN-03-FS-BPA-02.

4.4 Results

4.4.1 Price Results. The complete results of the Secondary Price Forecast can be found in the documentation for SN-03 Study, SN-03-FS-BPA-02, chapter 4. The results are expressed in terms of monthly average heavy load hour and light load hour prices. The following Tables 4-6 and 4-7 represent the prices as well as some summary statistics.

Table 4-6: FY 2003 Price Estimates

HLH	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03
Mean	40.29	44.25	54.76	58.68	60.02	61.20
Median	39.39	43.76	53.71	57.65	58.84	59.52
Maximum	88.53	84.51	105.80	106.03	106.95	136.25
Minimum	13.73	15.40	23.14	22.94	25.94	27.20
Stdev	10.87	9.65	12.27	12.36	12.13	13.70
LLH	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03
Mean	33.65	35.23	33.85	47.55	51.82	56.61
Median	32.74	34.73	32.40	46.40	50.68	55.27
Maximum	75.83	65.80	79.89	88.11	93.08	125.01
Minimum	12.30	14.77	15.05	15.79	23.89	25.66
Stdev	9.24	7.56	10.23	10.94	10.39	12.41

Table 4-7: FY 2004–2006 Price Estimates

HLH	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04
Mean	56.31	59.75	56.04	44.86	46.66	41.85	33.72	25.48	17.98	27.18	34.88	40.54
Median	55.19	58.52	54.34	43.54	45.11	40.30	32.15	22.96	16.81	24.96	33.96	39.94
Maximum	115.75	128.35	139.86	129.83	125.24	109.24	86.48	73.52	79.70	75.40	80.93	189.20
Minimum	26.19	25.51	21.63	9.74	12.21	12.39	7.46	2.91	2.70	3.80	13.20	13.93
Stdev	12.60	13.11	14.94	16.23	16.15	13.44	13.43	14.50	11.59	11.29	10.42	11.59
LLH	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04
Mean	47.51	49.07	46.89	35.04	38.49	33.58	29.63	20.79	12.51	21.29	32.38	39.45
Median	46.48	47.87	45.33	34.76	36.49	32.74	28.14	19.71	13.38	18.89	31.72	38.89
Maximum	96.90	109.42	107.55	103.11	119.52	91.24	74.64	57.24	43.06	60.49	71.05	82.16
Minimum	22.24	20.37	17.14	7.67	11.94	11.10	8.40	2.76	2.68	3.39	14.41	16.39
Stdev	10.43	10.86	12.99	13.01	13.49	10.28	11.10	9.47	6.66	8.65	8.79	10.21
HLH	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05
Mean	36.86	40.59	40.23	37.23	36.11	32.36	28.05	20.94	16.37	24.33	27.22	32.33
Median	36.22	39.78	39.64	36.18	34.50	31.48	26.33	19.01	15.41	22.66	25.64	31.18
Maximum	82.00	97.80	99.94	153.50	271.35	75.34	70.11	65.42	54.21	83.05	111.17	113.73
Minimum	13.78	15.45	10.60	6.54	6.79	5.47	3.66	3.13	2.77	3.67	12.44	13.02
Stdev	9.77	10.26	12.43	12.46	14.49	10.69	9.92	11.81	9.40	8.43	8.37	9.41
LLH	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05
Mean	33.66	35.44	33.17	29.87	30.83	28.54	24.88	18.52	13.00	21.16	26.66	32.07
Median	33.30	34.87	32.99	28.89	29.73	27.63	23.32	17.56	13.89	19.51	25.46	31.29
Maximum	74.69	86.61	74.72	79.41	101.51	65.53	60.01	50.94	40.04	53.13	64.58	76.96
Minimum	14.48	14.19	9.46	4.13	8.78	6.51	3.13	2.94	2.76	3.14	13.72	16.22
Stdev	8.60	8.64	10.39	10.00	10.77	8.74	8.12	7.42	6.60	6.82	7.13	8.23
HLH	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06
Mean	31.87	33.55	34.07	39.82	39.28	35.82	31.03	19.23	18.51	27.67	30.78	36.31
Median	31.22	33.08	33.26	39.69	38.31	35.08	30.04	17.10	17.40	26.34	29.00	34.86
Maximum	72.42	70.59	87.33	178.01	130.91	100.04	86.88	75.31	111.10	187.47	210.77	208.21
Minimum	15.39	15.30	13.49	4.95	3.80	4.47	3.88	2.86	2.83	3.66	10.86	14.19
Stdev	8.16	8.12	9.28	12.09	13.05	10.72	10.82	12.13	11.25	11.51	11.22	12.44
LLH	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06
Mean	28.51	29.12	28.99	32.98	34.16	32.16	27.74	17.94	13.72	23.22	30.21	35.75
Median	27.85	28.58	28.10	33.24	33.59	31.76	26.68	17.27	14.11	21.73	29.17	35.27
Maximum	58.51	58.54	66.96	121.85	117.36	90.06	72.90	64.20	51.24	70.54	76.06	83.32
Minimum	14.52	14.24	12.02	3.77	3.40	4.99	4.25	2.87	2.82	3.10	14.91	18.04
Stdev	6.99	6.85	7.70	10.55	10.75	9.00	8.54	8.63	7.58	8.22	7.82	8.73

4.4.2 Secondary Revenue Results. After the price distributions are generated by AURORA, the prices and corresponding surplus energy or deficit energy amounts are multiplied times the prices to derive estimated surplus sales and power purchase amounts. This occurs in the RiskMod model. The following tables reflect the expected (50^{th} percentile) secondary revenue, power purchases, and net revenue amounts. For FY 2003, actual sales (committed sales) and power purchases (committed purchases) were included in the forecast with transactions completed as of March 31, 2003. Table 4-8 reflects the FY 2003 secondary revenue forecast. For FY 2004-2006, estimated surplus revenues and expenses are reflected in Tables 4-9, 4-10, and 4-11.

Table 4-8: FY 2003 Secondary Revenue Forecast

FY 2003	Dollars	Price	AMW
Committed Sales	$499,254,000	$35.05	1,626
Forecasted Sales	$226,691,000	$47.05	550
Total Sales	$725,945,000	$38.08	2,176
Committed Purchases	$148,554,000	$34.89	486
Forecasted Purchases	$16,374,000	$47.93	39
Total Purchases	$164,928,000	$35.86	525
Net Revenue	$561,017,000	$38.79	1,651

Table 4-9: FY 2004 Secondary Revenue Forecast

FY 2004	Dollars	Price	AMW
Estimated Sales	$644,386,000	$28.84	2,551
Estimated Purchases	$7,645,000	$51.34	17
Net Revenues	$636,741,000	$28.68	2,534

Table 4-10: FY 2005 Secondary Revenue Forecast

FY 2005	Dollars	Price	AMW
Estimated Sales	$526,473,000	$24.03	2,501
Estimated Purchases	$8,365,000	$38.20	25
Net Revenues	$518,108,000	$23.89	2,476

Table 4-11: FY 2006 Secondary Revenue Forecast

FY 2006	Dollars	Price	AMW
Estimated Sales	$505,314,000	$24.12	2,392
Estimated Purchases	$17,387,000	$40.51	49
Net Revenues	$487,927,000	$23.77	2,343

4.4.3 Summary

Due to declining gas prices from the 2003 and 2004 time frame, BPA expects the weighted average sales price and secondary revenues to decline after 2004 for the remainder of the rate period.